THERMODYNAMIC PULSE LIFT OIL & GAS RECOVERY SYSTEM

REFERENCE TO PRIOR APPLICATION

This application is a divisional of U.S. Application Number 09/975,372, "Backwash Oil and Gas Production", filed October 11, 2001.

FIELD OF THE INVENTION

The present invention relates to a method of pumping crude oil, produce water, chemicals, and/or natural gas using an extremely efficient recovery system that conserves heat generated within the recovery system to further recovery of additional fluids. The invention further relates to thermodynamically efficient recovery systems with a novel internal integrated pump/injection system. The invention further relates to efficient recovery systems that may be integrated in a single component. The invention further relates to thermodynamically efficient oil and gas production systems with reduced environmental impact based on utilization of naturally occurring energy and other forces in the well and the process. The invention further relates to recovery systems controlled by naturally occurring gas from the well. The invention further relates to the prevention of decreased flow from a well due to corrosion, viscosity buildup, etc. downhole. The invention further relates to more cost-effective oil and gas production systems that costs less to purchase, maintain, and operate.

BACKGROUND OF THE INVENTION

Oil and gas recovery from subterranean formations has been done in a number of ways. Some wells initially have sufficient pressure that the oil is forced to the surface without assistance as soon as the well is drilled and completed. Some wells employ pumps to bring the oil to the surface. However, even in wells with sufficient pressure initially, the pressure may decrease as the well gets older. When the pressure diminishes to a point where the remaining oil is less valuable than the cost of bringing it to the surface using secondary recovery methods, production costs exceed profitability and the remaining oil is not brought to the surface. Thus, increasing the thermodynamic efficiency of secondary recovery means for fluids from subterranean formations is especially important for at least two reasons:

(1) Increased efficiency increases profitability, and

(2) Increased efficiency increases production.

Many forms of secondary recovery means are available. The present invention utilizes gas lift technology, which is normally expensive to install, operate and maintain, and often dangerous to the environment. Basically, gas lift technology uses a compressor to compress the lifting gas to a pressure that is

sufficiently high to lift oil and water (liquids) from the subterranean formation to the surface, and an injection means that injects the compressed gas into a well to a depth beneath the surface of the subterranean oil reservoir.

Since the 1960's gas lift compressors have used automatic shutter controls to restrict air flow through their coolers. Some even had bypasses around the cooler, and in earlier models some didn't even have a cooler. Water wells employing free lift do not cool the compressed air used to lift the water to the surface. Temperature control at this point has never been considered important other than to prevent the formation of hydrates from the cooling effect of the expanding lift gas. Therefore, most lifting has been performed with gas straight from the compressor. The heat of compression in this gas is not utilized effectively and is rapidly dissipated when the lift gas is injected into a well.

Compressors for this service are expensive, dangerous, require numerous safety devices, and still may pollute the environment. Reciprocating compressors are normally used to achieve the pressure range needed for gas lifting technology. Existing reciprocating compressors are either directly driven by a power source, or indirectly driven via a hydraulic fluid. While both are suitable for compressing lifting gas, most prior art reciprocating compressors are costly to operate and maintain. Moreover, existing reciprocating compressors are limited to compressing gases because they are not designed to pump both gas and liquids simultaneously and continuously.

Existing compressors use many different forms of speed and volume control. Direct drive and belt drive compressors use cylinder valve unloaders, clearance pockets, and rpm adjustments to control the volume of lift gas they pump. While these serve the purpose intended, they are expensive and use power inefficiently compared to the present invention. Some prior art compressors use a system of by-passing fluid to the cylinders to reduce the volume compressed. This works, but it is inefficient compared to the present invention.

Another example of wasted energy and increased costs and maintenance is in the way the compressing cylinders are cooled in prior art compressors. All existing reciprocating compressors use either air or liquid cooling to dissipate the heat that naturally occurs when a gas is compressed. The fans and pumps in these cooling systems increase initial costs, and require energy, cleaning, and other maintenance. Prior art reciprocating compressors also require interstage gas cooling equipment and equipment on line before each cylinder to scrub out liquids before compressing the gas.

Another example of the inefficiency of prior art technology relates to current means for separating recovery components. Existing methods employ separators to separate primary components, then heater treaters to break down the emulsions. In some cases additional equipment is required to further separate the fluids produced. In each case, controls, valves, burners and accessories add to the cost, environmental impact and maintenance of the equipment.

Prior art teaches injecting hot gas to try to create counter flowing temperatures. However, the hot gas upsets the natural state of the fluids in the well and its low density provides poor heating of the well piping where downhole buildup may interfere with fluid flow to the surface.

Thus, another problem plaguing current technology is downhole buildup of paraffin and other impediments to the smooth and continuous flow of oil to the well surface.

Hot gases work in thinning the fluids, but tend to cause corrosion of the well tubing and casing. Hot gases can also create chemical problems by causing the lighter hydrocarbons to flash out of the fluids downhole, making them more viscous as they cool. Steam works to a degree, but has similar problems with those caused by other hot gases, requires excessive caloric input, and adds water to the oil in the subterranean formation.

A superior method of combating downhole buildup of paraffin and other impediments employs the injection of hot oil or salt water to dilute the viscous fluids in the well. Hot oil works well, but until now was too costly to use without interrupting production. The usual method utilizing hot oil or hot salt water requires that the well be shut down, then oil or salt water is injected by a pumping unit immediately after heating it with a heating unit. This technology, which uses a truck/tank trailer with burners to heat the oil and pumps not only interrupts production, but is costly and dangerous.

SUMMARY OF THE INVENTION

The present invention is referred to herein as the THERMODYNAMIC PULSE LIFT OIL & GAS RECOVERY SYSTEM or "TRS". TRS was developed in connection with the "Backwash Production Unit" or "BPU", US Patent Application 09/975,372, which is hereby incorporated herein by reference. It was also developed in connection with the "Heat Exchange Compressor" or "HEC" which is the subject matter of US Patent Application ___________.

In it's broadest aspect the TRS uses a unique form of compression known as multi-phase pumping to recover oil and gas from a subterranean formation through an oil and gas well. More specifically, TRS compresses a portion of the production gas, captures heat from the compression process, transfers the heat to a portion of the production liquids, and injects cooled compressed gas and heated production liquids back into the well in large pulses to a sufficient depth that it mixes with crude oil downhole in the well. As a result, the compressed gas lifts crude oil up through the well to the surface, and the process is repeated using the newly produced production fluids.

The following disclosure sets forth the unique and innovative features of the TRS, describes the use of the TRS in the context of a BPU and a HEC, and illustrates how the TRS provides the ability to recover and transfer crude oil and natural gas from a subterranean formation well bore into a pipeline without additional equipment. In this context, the TRS receives natural gas and production liquids from a well into HEC pump cylinder(s) indirectly via a BPU vessel in which they are installed, uses heat generated during compression to increase the temperature of gases used for further fluid recovery, and elevates the pressure of the gas, oil, water and/or a mixture of them to a point that cylinder contents can flow into a pipeline.

In this context, the TRS utilizes a unique form of pulse lifting from a BPU. This is particularly attractive for enhancing production in that the compressor and pumping rates are controlled by wellhead pressure. In particular, the greater the wellhead pressure, the faster the TRS compresses and pumps. If the

wellhead pressure falls to zero (or a preset value), compression and pumping stop and waits for the well to recover. This pulse lifting combines the features of continuous and intermediate lifting. As with continuous lifting, control of the TRS requires a minimum amount of equipment. However, the large pulses provide the advantages of intermediate lifting.

The TRS is also particularly attractive for cost-effective production because it greatly reduces the cost of compressing the lifting gas and separating the components produced by the well. This is achieved by simplifying the design and by utilizing energy from the other components of the system that would otherwise be lost by prior recovery systems. Where the prior art uses gas compressors and pumps, the TRS pumps both gas and liquids simultaneously. Where the prior art requires coolers and fans, the TRS dissipates the heat of compression by using it in separating the fluids from the subterranean formation for cooling. Where the prior art uses special control and accessories to control volume as well as pumping and compression speed, the TRS may be controlled by the well head pressure. Where the prior art requires scrubbers to prevent liquids from entering the compression cylinders, the TRS function normally with liquids present. Where the prior art continues to use the same amount of energy when production falls, the TRS automatically adjusts its stroke length and pumping rates to match the lower level of recovery. When fluid levels drop at the wellhead, the TRS automatically adjusts piston speed and stroke to optimize gas injection to maintain maximum lift.

Another aspect of the TRS is its capability to safely and efficiently heat salt water and inject the hot liquid into the well without interrupting production. This water may be injected with the lift bubble as a pulse below the standing level of the reservoir. As the warm liquid falls slowly through the bore hole, it warms and treats them and the well.

When hot oil injection is required, the TRS injects lift gas mixed with oil down the well injection string, coating and heating the wall of the piping. In this manner, the TRS greatly improves prior art methods of combating downhole buildup of paraffin and other impediments and thereby facilitates flow of production fluids to the well surface.

Integrating HEC and BPU technology into the TRS eliminates sealing packing, and therefore has substantially fewer moving parts than prior art technology. This reduces the danger of operating the recovery system and further reduces both initial costs as well as maintenance and operation costs. Another advantage of the TRS is that its power source and directional control can be remotely located, thereby reducing maintenance and downtime.

The TRS employs technology well known in the art in a novel manner. Free gas lift has been employed for many decades with excellent results, but it is expensive to install and maintain. The TRS greatly improves the efficiency of using free lift by ejecting the gas in very slow strokes (forming pulses). These pulses allow the normally continuous lift to emulate intermittent lift. Hot oil treatment is also well known in the art, but has the disadvantages described previously. The TRS is capable of pumping gases, fluids, or any combination thereof into the well, thereby permitting simultaneous pressurized gas lift and well bore treatment with hot oil. Separation equipment for the oil and gas recovered at the wellhead, integrated within a single piece of equipment, permits the TRS to switch modes from a lifting system to a pipeline selling mode and back

again automatically. When more gas than is needed for lifting is recovered from the well, the excess gas is sent into a collection system or a pipeline. Similarly, oil recovered from the subterranean formation is heated to facilitate separation and the excess is distributed for storage or sale.

Another extremely attractive aspect of the TRS is that it can be safely installed at the wellhead. Shorter piping requirements, reduced pressure differentials, the lack of danger from burners, and the reduced danger from electrical sparks all contribute to the TRS's safety.

BRIEF DESCRIPTION OF THE FIGURES

Fig. 1 ... Schematic illustration of the TRS a backwash production context.

Fig. 2 ... Illustration of the TRS using a HEC to compress gases for lifting and production.

Fig. 3 ... Illustration of the TRS using a BPU oil/gas/water separator as an immersion vessel and a HEC as a compressor.

Fig. 4 ... Illustration of the TRS using a HEC in a backwash production context.

Fig. 5 ... Illustration of the TRS with a HEC immersed in a separator.

Fig. 6 ... Illustration of the TRS with a HEC creating backwash.

Fig. 7 ... An embodiment of the TRS with a HEC in a backwash production context.

Fig. 8 ... An illustration the TRS for use in an underwater backwash production context.

Fig. 9 ... An embodiment of the TRS in a well requiring higher pressure gas injection.

While preferred embodiments of the invention are described using a HEC in a backwash production context, it will be understood that it is not intended to limit the invention to those embodiments or to use with a HEC or in a BPU. On the contrary, it is intended to cover all applications, uses, alternatives, modifications, and equivalents as may be included within the spirit and scope of the invention as defined by the appended claims.

DESCRIPTION OF THE INVENTION

The TRS is designed primarily for oil and gas recovery from small or low volume producing wells where some natural gas is recovered and gas lift may be used to recover crude oil from a subterranean formation. In what follows "recovery" refers to the process of bringing oil and natural gas to the well surface whereas "production" refers to the portion of recovered oil and natural gas that is stored or sold.

The TRS performs many oil field related tasks including hot oil treatment, chemical treatment, flushing, pressure testing, emulsion treatment, and gas and oil recovery using a single piece of equipment. Optimizing and multi-tasking common components ordinarily used in separate pieces of equipment sets the TRS apart from any existing equipment currently in use for crude oil recovery.

The TRS employs technology well known in the art in a novel manner. Free gas lift has been employed for many decades with excellent results, but it is expensive to install and maintain. Working together, the TRS, HEC and BPU greatly improve the efficiency of using free lift by ejecting the gas in very slow strokes (forming pulses). Hot oil treatment is also well known in the art, but has the disadvantages described previously. The TRS may pump gases, liquids, or any combination thereof into the well, thereby permitting

cooled, pressurized gas lift and bore hole treatment with hot oil simultaneously. Separation equipment for the oil and gas recovered at the wellhead, integrated within a single piece of equipment, permits the TRS to switch modes from a lifting system to a pipeline selling mode and back again automatically. When more gas than is needed for lifting is recovered from the well, the invention sends the excess into a collection system or a pipeline. As oil is recovered from the subterranean formation, it is heated to facilitate separation and recovered for storage or sale. Moreover, the invention can be outfitted with metering to monitor dispersal to the end user.

In its most general aspect, the primary function of the TRS is to use gas to lift oil and water (liquids) from a subterranean formation for storage or sale. Fig. 1 illustrates these general aspects schematically. The embodiment of the BPU therein comprises well 100, compressor 102, pump 104, power supply 106, and separator 108. Well 100 comprises injection chamber 110, lifting chamber 112, and casing chamber 114. HEC components include compressor 102, pump 104, power supply 106 and separator 108. Compressor 102 comprises at least two compressing units, depending on the depth of the well and other recovery requirements. For example, additional cylinders may be added for wells capable of greater production, and a higher pressure cylinder may be added to obtain higher pressures of lift gas that may be necessary for efficient recovery from deep wells or for well maintenance. Pump 104 may be a hydraulic pump capable of pumping sufficient hydraulic fluid to compress lift gas for well 100 using compressor 102. Power supply 106 may be an electric motor or natural gas engine capable of powering pump 104. Separator 108 comprises a means of separating gas, crude oil, and water, and contains compressor 102.

As illustrated in Fig. 1, crude oil, gas and water from well 100 may be piped to separator 108 via inlet 116. Gas at wellhead pressures in separator 108 supplies the lift gas to be compressed in compressor 102, which may be used as lift gas or stored or sold as production gas, supply gas for pressure monitoring information, and fuel for power supply 106. Oil in separator 108 supplies heated oil for injection into well 100, crude oil produced for storage or sale, and coolant for compressor 102. Water in separator 108 supplies heated water for injection into well 100 and coolant for compressor 102. Liquids may be injected after adding chemicals via valve 118. Power supply 106 supplies the power for pump 104, which moves the fluid that powers compressor 102. Compressor 102 compresses gas from the wellhead pressure to the pressure necessary for lifting liquids through well 100 and supplies heat to the surrounding liquids in separator 108.

Figure 2 further illustrates the TRS with a HEC compressing gasses for lifting and production in the backwash production context. In the embodiment illustrated in Fig. 2, cooled compressed gas is injected from compressor 200 into bore hole 202 of well 204 to the bottom of tubing 206, which is down hole 202 sufficiently far to be immersed in liquid 208 in subterranean formation 210. When the compressed gas reaches the bottom of tubing 206, it escapes into casing 212 in hole 202. Since the compressed gas is lighter than liquid 208, the gas rises through liquid 208 as bubbles. During its trip upward through casing 212, the surrounding pressure decreases and the bubbles become larger. As is well known in the art, this action causes the gas to lift liquids above it toward well surface 214. When the bubbles and lift liquids reach surface 214, they enter separator 216, which also houses compressor 200. Optionally, compressor 200 may be used to simultaneously inject heated liquids recovered from well 204 back into well 204 for maintenance thereof.

Fig. 3 illustrates TRS with a separator serving as the immersion vessel for a HEC. The separator technology shown is well known in the art (See, for example, the 3-phase horizontal separator available from Surface Equipment Corporation). Tank 300 in Fig. 3 holds a mixture of water, oil and gas, which layer according to their densities, with gas in top layer 302, oil in middle layer 304, and water in bottom layer 306. In the embodiment illustrated in Fig. 3, tank 300 is divided by weir 308 into 3-phase section 310 to the left (3-phase side) of weir 308 and 2-phase section 312 to the right (2-phase side) of said weir. Section 310 may contain gas, oil and water whereas section 312 may contain only gas and oil. Water/oil level control means 314, which may be a Wellmark level control device or other equipment well known in the art, detects the water/oil interface level in section 312 of tank 300. Means 314 ensures that the water level in section 312 does not exceed the height of weir 308. If the water level exceeds a level set by means 312, water dump valve 316 opens, thereby removing water from tank 300 via water outlet 318 until the water returns to the set level, at which time means 314 causes valve 316 to close. Said water may be cycled for injection, with or without added chemicals, for well maintenance, or stored. Oil/gas level control means 320, which may also be a Wellmark level control device or other equipment well known in the art, detects the gas/oil interface level in section 312 of tank 300. The purpose of means 320 is to control the oil level in tank 300. If the oil level exceeds a level set by means 320, oil dump valve 322 opens, thereby removing oil from tank 300 via oil outlet 324 until the oil returns to the set level, at which time means 320 causes valve 322 to close. Said oil may be cycled for injection and well maintenance, or stored or sold. Sight glass 326 provides the user with a means for visually inspecting the levels of water and oil in tank 300.

Tank 300 also includes inlet 328 from well 330, line 332 from the top (gas phase) portion of tank 300 to compressor 334, gas outlet 335 from compressor 334, and instrument supply gas outlet 336. A sufficient volume of gas from layer 302 travels via line 332 to compressor 334 where it is compressed for injection into well 330 or sale. Gas from layer 302 exiting tank 300 via outlet 336 may be used to control TRS instrumentation.

Compressor 334 comprises at least two compressing units, depending on the depth of the well and other recovery requirements. For example, additional cylinders may be added for wells capable of greater production, and a higher pressure cylinder may be added to obtain higher pressures of lift gas that may be necessary for efficient production from deep wells or for well maintenance.

Recovery using the embodiment illustrated in Fig. 3 may be facilitated by turbocharger or blower 338, which may reduce the pressure in tank 300 and well 330 without affecting the pressure between the gas in line 332 and compressor 334. Spring loaded check valve 340 may be used to limit the flow of gas to compressor 334 when the wellhead pressure is low.

Fig. 4 illustrates an embodiment of the TRS with a HEC in a backwash production context. In Fig. 4 low pressure cylinder 400 contains low pressure piston 402 and low pressure piston head 404, and high pressure cylinder 406 contains high pressure piston 408 and high pressure piston head 410. Both cylinders 400 and 406 may pump liquids as well as gases. The purpose of cylinder 400 is to compress gas to an interstage pressure, and the purpose of cylinder 406 is to further compress said gas to a pressure sufficient to lift liquids as

illustrated in Fig. 2. Accordingly, cylinder 406 has a smaller radius than cylinder 400. As described above, cylinders 400 and 406 not only pump gases, but may also pump liquids, for example, for injecting hot liquids for well maintenance.

Both pistons 402 and 408 are shown in Fig. 4 in their respective cylinders before gas has been admitted therein. Natural gas from well 412, which may be mixed with liquids in cylinder 400 as described above, is permitted to enter cylinder 400 via first cylinder inlet valve 414, intercylinder piping 416 via first cylinder outlet valve 418, and cylinder 406 via second cylinder inlet valve 420, thereby causing pistons 402 and 408 to begin their stroke by displacing them to the right in cylinders 400 and 406, respectively in Fig. 4. When sufficient gas has been admitted into said cylinders and intercylinder piping to provide gas compressed to the desired interstage pressure, valve 414 closes, and fluid, which may be hydraulic fluid, crude oil or engine oil, from reservoir 422 is pumped into ram portion 424 of cylinder 400 by pump 426 via directional control valve 428, causing piston 402 to move to the left and thereby compressing said gas in said cylinders and intercylinder piping. When said gas in said cylinders and piping reaches the desired interstage pressure, valve 420 closes, valve 428 switches flow of said fluid from cylinder 400 to cylinder 406, and said fluid from reservoir 424 is pumped into ram portion 430 of cylinder 406 by pump 426, causing piston 408 to move to the left and thereby further compressing said partially compressed gas in cylinder 406. Simultaneously, when valve 428 switches, said interstage pressure of said gas in cylinder 400 causes piston 402 to move back to the right in cylinder 400 in Fig. 4. When said gas in cylinder 406 is compressed to the desired pressure for lifting liquids from a subterranean formation, second cylinder outlet valve 432 opens and said compressed gas leaves cylinder 406 and may be used as lift gas for lifting liquids through well 412 as illustrate in Fig. 2 or it may be stored or sold. As described above, the entire process described in this paragraph may take place with liquids mixed with the gas undergoing compression. Moreover, heat from compressions in cylinders 400 and 406 is absorbed in separator 434. Gases that leaks past piston head rings 436 and 438 may be scavenged from said ram portions of cylinders 400 and 406 and recycled to separator 434 or to cylinder 406, where they may be compressed during the next stroke.

Slow stroke compression in cylinders 400 and 406 permit cylinder 400 to act as a charging pump for cylinder 406 and automatically changes the stroke of piston 408 as needed for production from well 412.

Cylinders 400 and 406 are lubricated by the fluid from reservoir 422. Contaminating liquids which may inadvertently mix with said fluid may be removed by means well known in the art, using, for example, blow case/separator 440. In the embodiment shown in Fig. 4, fluid contaminated with water cycles through oil/water separator 442 wherein oil/water interface level control 444 is used to control the level of water. Water may be removed from the bottom of separator 442 via dump valve 446 when the water level increases over the threshold set by control 444. Oil may be removed from the top of separator 442 via line 447 and pressure regulator 448 to filter 450, which is also used to filter fluid cycled back from said ram portions of cylinders 400 and 406 via valve 428, monitor levels of said fluids, and shut down pump 426 if said fluid levels are too low.

When fluid is flowing from valve 428 to cylinders 400 and 406 said flow may be controlled by directional control pilot valves. For example, in the embodiment illustrated in Fig. 4, pressure of fluid flowing

from valve 428 to ram portion 424 of cylinder 400 may be monitored by a first directional control pilot valve 452, and pressure of fluid flowing from valve 428 to ram portion 430 of cylinder 406 may be monitored by a second directional control pilot valve 454. Valve 428 may thereby be set to trip if pressure is too high, thereby stalling the compression strokes.

Moreover, pump 426 may be controlled by the pressure of gas entering cylinder 400. In the embodiment illustrated in Fig. 4, 2-way valve 452, which may be, for example, a Kimray 1" PC valve, is controlled by the pressure of gas entering cylinder 400 such that valve 452 diverts the flow of pump 426 when pressure is too low.

Power source 455, which may be an electric motor or a gasoline or natural gas engine, may be outfitted with spring loaded actuator 456 to reduce engine or motor speed when the TRS is not pumping. In addition, power source 455 may be outfitted with a turbocharger or blower connected via line 458 to separator 434 to reduce the pressure therein without removing the pressure to cylinder 400, but thereby reducing the wellhead pressure over well 412.

Fig. 5 further illustrates the TRS using a HEC immersed in a separator. In Fig. 5 low pressure cylinder 500 and high pressure cylinder 502 are mounted inside separator 504. The lift gas may be combined with liquids in mixer 506 prior to introduction of the gas into cylinder 500. In this disclosure this process of combining the lift gas with liquids is referred to as "natural mixing," and lift gas is referred to as "gas" or "lift gas" whether or not natural mixing has taken place. As illustrated in Fig. 5, the invention is outfitted with internal heat exchanger 508, which provides an alternative means of heating or cooling the contents of separator 504. In some cases it may be necessary to externally mount additional piping 510 for the compressed gas, with or without liquids to achieve proper heat transfer. Fig. 5 illustrates how heat generated during compression of gas may be utilized to heat oil or water that may be used, for example, for well maintenance. Moreover, the compressed lift gas is cooled, thereby eliminating the adverse effects of injecting hot gases well known in the art.

Figs. 5 and 6 illustrate the "backwash" effect for which the BPU invention is named as well as how the TRS uses that effect. As illustrated in Fig. 5, the liquids to be injected may be heated using the heat generated by compressing gas, and then injected, for example, for well maintenance or salt water disposal. In Fig. 6, gas collected in separator 600 flows through spring-loaded low compression cylinder check valve 602 into low compression cylinder 604, intercylinder piping 606, and high compression cylinder 608. The setting for valve 602 controls the minimum pressure that will initiate a compression stroke in cylinder 604. After compression, gas may leave cylinder 608 via high compression cylinder outlet spring-loaded check valve 610. The setting for valve 610 controls the minimum pressure at which gas may leave cylinder 608. The gas leaving cylinder 608 may be vented, or flow to 3-way valve 612, which may be a 1" Kimray valve. The position of valve 612 may be controlled by pilot valve 614, which, in turn is controlled by the gas pressure in separator 600. Depending on the position of valve 612, the gas from cylinder 608 is used as lift gas or sold. This feature of the TRS is unique in that the wellhead pressure controls recovery: Gas from the well is automatically used to try to increase recovery when recovery is low but is automatically diverted for sale when recovery is normal.

Since the TRS valving is designed for liquid and/or gas flow, cylinders 604 and 608 may pump liquids as well as gases. Therefore, lift gas injected by the present invention may be accompanied by heated water from separator 600 if valve 612 is open, heated oil from separator 600 if valve 614 is open, and both liquids when both valves 612 and 614 are open. This feature prevents any liquid carryover from separator 600 from damaging the invention. In one preferred embodiment of the present invention, valve 602, which may have a load of 10 pounds and valve 610, which may have a load of 80 pounds, permit the invention to pump as much as 100 gallons per minute of liquid into well 616 with or without lift gas.

This integration of the separator with the pumping cylinders (for example, separator 504 & cylinders 500 and 502 in Fig. 5) and fluid permissive valving (for example, valves 602, 610 and 612 in Fig. 6) sets the TRS apart from all other recovery systems. As described previously, this design reduces the need for burners, heaters, treating pumps, coolers, fan, scrubbers and many other components normally used for oil and gas production.

As described above, injection of hot gases to lift liquids from subterranean formations is well known in the art. However, since natural gas is a poor carrier of heat, the heat carried by injected gas dissipates within the first few feet where it flows down the well hole. As illustrated in Fig. 6, the TRS avoids this problem by pumping heated fluids from separator 600 through an injection valve 618 down injection tubing 620 in well 616 following natural mixing. The liquids mixed with the lift gas forms a film inside tubing 620, thereby warming it and reducing the cooling effect of the expanding lift gas.

The backwash capability also permits the TRS to backwash heated liquids from its separator directly into either the casing side or the injection tubing of well 616. This is illustrated in Fig. 6 wherein liquids heated in separator 600 flows directly to tubing 620 via tubing injection valve 618 or directly to the casing side of well 616 via casing injection valve 622. This arrangement permits the invention to remove paraffin buildup and otherwise maintain the well hole by injecting hot liquids without interrupting production. Alternatively, valves 618 and 622 may be used to inject water, for example, to dissolve downhole salt buildup.

In the embodiment of the TRS illustrated in Fig. 7, gas from casing 700, recovery tubing 702, and injection tubing 704 of well 706 flows via well casing output valve 708, recovery tubing well output valve 710, and injection tubing well output valve 712 into well output line 714 and thence into separator input check valve 716 to recovery inlet 718 of separator tank 720 at separator pressures in the range 40 PSIG. Said gas enters separator gas outlet line 722, which is installed vertically in tank 720, and flows through separator gas outlet valve 724, spring loaded check valve 726, and low compression cylinder inlet valve 728 to low compression cylinder 732. The pressure from said gas entering cylinder 732 displaces head 730 of low compression piston 734 in cylinder 732 to the right into ram portion 736 of cylinder 732 and head 738 of high compression cylinder 740 into ram portion 742 of cylinder 740. When sufficient gas has entered said cylinders and intercylinder piping 744 to provide gas compressed to the desired interstage pressure, valve 726 closes. Engine 746, which may be an electrical motor, natural gas engine, or the like, supplies power to pump 748, which may be a hydraulic pump. Pump 748 pumps fluid, which may be hydraulic fluid, crude oil, engine oil, or the like, from fluid source 750 at pressures in the range 3000 PSIG through directional control valve 752 into portion 736 of

cylinder 732 on the opposite side of head 730 via low pressure cylinder fluid inlet line 754, thereby compressing gas in compression chamber 756 of cylinder 732, intercylinder piping 744 and compression chamber 758 of cylinder 740 to a pressure in the range 100-350 PSIG while displacing gas from cylinder 732 through low compression cylinder gas outlet check valve 760. The partially compressed gas leaving cylinder 732 is cooled inside internal heat exchange unit 762, which is part of piping 744 immersed in tank 720. As described above, said gas has entered compression chamber 758 of cylinder 740 via high compression cylinder input valve 764 during compression in cylinder 732, thereby displacing high compression piston 766 to the right into ram portion 742 of cylinder 740. When piston 734 has completed its compression stroke, pressure switch 768 for cylinder 732 is tripped, thereby changing the position of valve 752 to permit flow of fluid into ram portion 742 of cylinder 740. Pump 748 pumps fluid at pressures in the range 3000 PSIG through valve 752 and line 769 into ram portion 742 of cylinder 740 on the opposite side of head 738, thereby compressing gas in compression chamber 758 to the pressure necessary to lift liquids from the subterranean formation, and thence displaces said gas out through high compression cylinder gas outlet spring loaded check valve 770. Meanwhile, depending on the wellhead pressure and the spring load in valve 726, additional gas from well 706 may refill chamber 756 of cylinder 732 and piping 744, thereby displacing piston 734 to the right into ram portion 736. When valve 770 opens, thereby enabling the compressed gas to leave chamber 758 of cylinder 740, said new gas from well 706 also refills chamber 758 of cylinder 740, thereby displacing piston 766 to the right into ram portion 742. When piston 766 reaches the end of its compression stroke, valve 752 switches back to the position wherein fluid is pumped into cylinder 732 by pump 748, thereby initiating the next compression stroke, as described above. Valve 752 also enables cylinders 732 and 740 to empty fluids displaced from their ram portions 736 and 742 as described above. Oil and gas that may leak across piston heads 730 or 738 into ram portions 736 or 742 may be returned to cylinder 732 via oil and gas recycle line 772 and valve 728. Alternatively, gas that may leak across piston heads 730 or 738 may be used as fuel after recovery through gas recycle line 774 and fluid filter system 776. In another alternative, oil and water that may leak across piston heads 730 or 738 may be directed through oil and water recovery line 778 to oil/water separator 780, and the oil recovered there from.

In the preferred embodiment illustrated in Fig. 7, valve 770 may be a spring loaded check valve set for an 80 pound load. In that embodiment, only when said gas pressure in compression chamber 758 exceeds 80 PSIG, said gas may flow through high pressure gas outlet line 782 to 3-way motor valve 784. If this condition is met, valve 770 opens after compression in chamber 758 is complete, and the compressed gas may be diverted through valve 784 to metered pipeline 786 or storage tank 788, or said compressed gas, with or without natural mixing with liquids, may be injected into well 706. The position of valve 784 may be controlled by the pressure of gas leaving tank 720 at outlet 722 via line 790 through gas pilot valve 792. When the pressure of gas leaving tank 720 equals or exceeds a threshold value which may be set by the user, pilot valve 792 permits the flow of instrument gas from tank 720 to valve 784, thereby setting valve 784 to permit the flow of compressed gas to pipeline 786 or tank 788. Alternatively, when said pressure becomes less than said threshold value, pilot valve 792 blocks the flow of instrument gas to valve 784, thereby switching valve 784 to block flow to pipeline 786

or tank 788 while still permitting the flow of compressed gas from cylinder 740 to injection line 794 for injection as lift gas into well 706. Optional signal shut-off 796 may be included between valve 770 and valve 784 to provide a means of shutting off lift gas during injection of hot liquids from cylinder 740.

Specifically, lift gas may be injected in injection tubing 704, where said gas travels down to the bottom of said tubing and bubbles out through liquids resting in the subterranean formation. In the preferred embodiment illustrated in Fig. 7, the gas temperature and the liquid temperatures are similar. As the gas bubbles rise, they expand and cool. This cooling effect is offset by the density of the surrounding liquids. At this point during recovery the TRS is capable of capitalizing on its inherent ability to heat liquids in tank 720 and use the heat as needed for efficient oil recovery. In particular, heated liquids may be pumped from tank 720 into tubing 704 as needed to offset the cooling effect described above. In this preferred embodiment of the invention, the heated tubing helps maximize the expansion effect of the bubbles as they continue to rise and expand, thereby starting the liquid lift through recovery tubing 702. Both tubing 702 and 704 may be installed as open ended tubing as required for the liquid level in the subterranean formation. When the lifted liquids reach the surface, they enter tank 720 as described above.

In the preferred embodiment illustrated in Fig. 7, the gas, oil and water from the subterranean formation are separated in tank 720. Tank 720 in Fig. 7 holds a mixture of water, oil and gas, which layer according to their densities, with gas in top layer 798, oil in middle layer 800, and water in bottom layer 802. In the embodiment illustrated in Fig. 7, tank 720 is divided by weir 804 into 3-phase section 806 to the left of weir 804 and 2-phase section 808 to the right of said weir. Section 806 may contain gas, oil and water whereas section 808 may contain only gas and oil. Water/oil level controller 810, which is a device well known in the art such as a Cemco liquid level controller, detects the water/oil interface level in section 806 of tank 720. When the water/oil interface level equals or exceeds a threshold value which may be set by the user, instrument gas flowing through controller 810 causes injection water dump valve 812 to open, thereby removing water from tank 720. On the other hand, when the interface level is less than said threshold value, instrument gas stops flowing through controller 810, thereby causing dump valve 812 to close. Similarly, oil/gas level controller 814 detects the oil/gas interface level in section 808 of tank 720. When the liquid level equals or exceeds a threshold value which may be set by the user, instrument gas flowing through controller 814 causes oil dump valve 816 to open, thereby removing oil from tank 720. On the other hand, when the liquid level is less than said threshold value, instrument gas stops flowing through controller 814, thereby causing dump valve 816 to close. Sight glass 818 provides the user with a means for visually inspecting the levels of water and oil in tank 720. When manual oil valve 820 is open or when pilot valve 792 is blocking valve 784 so that oil motor valve 822 is open, oil flows from tank 720 to storage tank 824 or metered pipeline 825, but when valve 820 and valve 822 are closed, oil flows into cylinder 732 via oil recycle line 826 and valve 728 for injection into well 706. Similarly, when water manual valve 828 or water motor valve 830 are open water flows from tank 720 to storage tank 832, but when valve 828 and valve 830 are closed, water flows into cylinder 732 via water recycle line 834 and valve 728 for injection into well 706.

Accordingly, valves 792, 784, 820, 822, 828 and 830 operate to control the flow of oil for injection with lift gas as follows:

IF 792=0, 784=0, NO GAS IS BEING RECOVERED 822=0, AND 830=0
IF 820=0, OIL FLOWS FOR INJECTION
IF 820=1, OIL IS BEING STORED
IF 828=0, WATER FLOWS FOR INJECTION
IF 828=1, WATER IS BEING STORED
IF 792=1, 784=1, GAS IS BEING RECOVERED, 822=1, AND 830=1
IF 820=0, OIL IS BEING STORED
IF 820=1, OIL IS BEING STORED
IF 828=0, WATER IS BEING STORED
IF 828=1, WATER IS BEING STORED

This arrangement prevents liquids from tank 720 from being mixed with production gas. It merely requires that an operator keep both manual valves open except during oil or water injection.

Tank 720 also includes instrument supply gas outlet 836. The pressure of supply gas from outlet 836 is regulated by regulator 837, which may be set at 35 PSIG for the embodiment illustrated in Fig. 7. In addition to supplying gas for controllers 810 and 814, said supply gas is used in separator 780 to detect the water/oil interface therein using liquid level controller 838. When the oil/water interface level equals or exceeds a threshold value which may be set by the user, instrument gas flowing through controller 838 causes water dump valve 840 to open, thereby removing water from separator 780. On the other hand, when the interface level is less than said threshold value dump valve 840 closes. In addition to pilot valve 792, supply gas from tank 720 is also used in low fluid pressure pilot valve 842 and high fluid pressure pilot valve 844 which control valve 752. In the embodiment illustrated in Fig. 7 the threshold supply gas pressure that opens valve 752 may be set at 10 PSIG.

Gas from tank 720, in addition to being used for lifting and for sale, may also be used, for example, as fuel for engine 746, or other purposes. Oil, in addition to being used for injection and well maintenance and for sale, may also be used as coolant for cylinders 732 and 740, or it may be used, for example, as fluid for pump 748, or other purposes. Water, in addition to being used for injection and well maintenance, may also be used as coolant for cylinders 732 and 740.

Gas pressure in tank 720 may be limited by separator relief valve 846, which may be set at 125 PSIG for the embodiment illustrated in Fig. 7. Control of pump 748 is coordinated with control of compression by cylinder 734 by the gas pressure in tank 720. If the pressure between valves 724 and 726 is less than the amount set for valve 726, valve 726 remains closed, and compression in cylinder 734 stops. Simultaneously, the pressure between valves 724 and 726 control 2-way motor valve 850 such that when said pressure is less than an amount which may be set by the user, for example, 10 PSIG, valve 850 is open and fluid cannot flow to

valve 752 or cylinders 732 and 740. When said gas pressure exceeds the amount set by the user, valve 850 closes, and pump 748 pumps fluid to valve 752. For the embodiment illustrated in Fig. 7, valve 726 and valve 850 may be set at 10 PSIG so that the flow of hydraulic fluid through valve 752 cannot occur when the wellhead pressure is insufficient for compression. Pump 748 then cycles fluid under control of relief valve 852 without pumping said fluid to ram portions 736 and 742 for compression. In the embodiment illustrated in Fig. 7, pump 748 is further protected by low level shutdown 854 in fluid filter system 776. Moreover, when engine 746 is a gas powered engine, engine temperature and oil pressure may be controlled by shutdown mechanisms well known in the art. In another embodiment of the invention, pump 748 and engine 746 may be remotely located away from the recovery area, and may serve more than one production unit.

Fig. 8 illustrates how waterproof TRS 880 may be operated submerged in water 882 near underwater well 884 using engine 886 and pump 888, both of which are located above the surface of water 882 on platform 890.

Fig. 9 illustrates an embodiment of the invention with one additional cylinder added for applications requiring higher lift gas pressure or for well maintenance with high pressure gas. In Fig. 9, compressed gas from high pressure gas outlet line 900 of the 2-cylinder embodiment in Fig. 7 is diverted to supplemental cylinder 902 via line 900 and gas inlet valve 906. Cylinder 902 comprises compression chamber 908 which is to the left of piston head 910 of piston 912. In Fig. 9 gas outlet valve 914 is initially closed, piston 912 is initially located midway in cylinder 902, and ram portion 916 of cylinder 902 is to the right of piston 912. When said compressed gas fills chamber 908, piston 912 is displaced to its rightmost position and valve 906 closes. After cylinder 902 is filled with said compressed gas, fluid is pumped from fluid source 918 by pump 920 and power source 921 through manual control valve 922 via fluid supply line 924 into portion 916 of cylinder 902, displacing piston 912 to the left and thereby compressing said compressed gas further to higher pressure, which may be required, for example to lift liquids, for well maintenance, and the like. Said gas at said higher pressure may be injected into well 926 via injection line 928 by opening valve 914. After injection, valve 914 closes, valve 906 opens, gas from line 900 entering chamber 908 displaces piston 912 to the right, thereby displacing fluid from portion 916 from cylinder 902. Fluid is again pumped into portion 916, thereby starting the next compression stroke for cylinder 902 as described above. Excess gas from chamber 908 and portion 916 of cylinder 902 may be recycled to separator tank 930 via lines 932 and 934 and recovery inlet 936.

Example 1:

The average well performs best with 40-60 PSIG back pressure on the lift system. The following example uses 40 PSI as the operating pressure in a BPU using a HEC with two cylinders with 108" strokes and 1.1875" ram cylinder bore radiuses and a 30 gallon per minute hydraulic pump. The low compression cylinder has a bore radius of 4" and the high compression cylinder has a bore radius of 2".

Maximum Ram Pressure Available: 3000 PSIG

Input Pressure to First Cylinder: 40 PSIG

Swept Volume of First Cylinder: 5430 Cubic Inches

Input Volume to First Cylinder: 11.7 Standard Cu.Ft. Gas

Minimum Ram Pressure Required for First Cylinder: 2537 PSIG

Discharge Pressure from First Cylinder: 210 PSIG

Discharge Swept Volume from First Cylinder: 1357.7 Cubic Inches

Minimum Ram Pressure Required for Second Cylinder: 2864 PSIG

Input Volume to Second Cylinder: 2.85 Cubic Feet

Discharge Pressure from Second Cylinder: 1000 PSIG

Discharge Volume from Second Cylinder: .631 Cubic Feet

Example 1 injects .631 cubic inches of compressed lift gas into a well 6 to 8 times per minute, thereby creating a bubble 11.7' long in a 4" ID casing with 2 3/8" OD injection tubing each time. As this bubble rises, it increases in size to 207' long.

Example 2:

The engine in Example 1 controls the pump frequency. Lifting capacity is controlled by the volume of the low pressure cylinder, the pressure ratio, and the number of strokes per time unit. For a gas from the separator at 40 PSIG, a pressure ratio of 4.1, and a frequency of 6 to 8 strokes per minute, the lifting capacity of the unit in Example 1 is 114,180 cubic feet per day. Based on 1/3 HP per gallon per 500 PSI, the power required to lift this volume is 56.57 horsepower (peek load at the end of the stroke) or 33.6 horsepower (average for entire stroke) for both cylinders at maximum operating pressures.

Example 3:

Over a two hour period during which oil and water are lifted from the well, 40,000 BTU is transferred from the compression cylinders of Example 1 to 4,000 pounds of water in a separator with a three stage capacity of 900 BBL/day, thereby increasing the water temperature 100 degrees F. This hot water is injected into the well for maintenance without interrupting production.

Example 4:

The following example uses 40 PSI as the operating pressure in a BPU using a HEC with two cylinders with 234" strokes and 1.1875" ram cylinder bore radiuses and a 60 gallon per minute hydraulic pump. The low compression cylinder has a bore radius of 4" and the high compression cylinder has a bore radius of 2".

Maximum Ram Pressure Available: 3000 PSIG

Input Pressure to First Cylinder: 40 PSIG

Swept Volume of First Cylinder: 11,766.86 Cubic Inches

Input volume to First Cylinder: 25.34 Cubic Feet

Minimum Ram Pressure Required for First Cylinder: 2537 PSIG

Discharge Pressure from First Cylinder: 210 PSIG

Discharge Volume from First Cylinder: 6.168 Cubic Feet
Minimum Ram Pressure Required for Second Cylinder: 2864 PSIG
Discharge Pressure from Second Cylinder: 1000 PSIG
Swept Volume of Second Cylinder: 2941.71 Cubic Inches
Discharge Volume from Second Cylinder: 1.366 Cubic Feet

Example 4 injects 1.366 cubic feet of compressed lift gas into a well 6 to 8 times per minute, thereby creating a bubble 24.17' long in a 4" ID casing with 2 3/8" OD injection tubing. As this bubble rises, it increases in size to 448.5' long.

Example 5:

For a gas from the separator at 40 PSIG, a pressure ratio of 4.1, and a frequency of 8 strokes per minute, the lifting capacity of the unit in Example 4 is 231,770 cubic feet per day. Based on 1/3 HP per gallon per 500 PSI, the power required to lift this volume is 113.44 horsepower (peek load) or 67.98 horsepower (average load) for both cylinders at maximum operating pressures.

Example 6:

Over a one hour period during which oil and water are lifted from the well, 65,000 BTU is transferred from compression cylinders of Example 4 to 13,000 pounds of oil in a separator with a three stage capacity of 100 BBL/hour. The oil temperature increases 100 degrees F. This hot oil is injected into the well for maintenance without interrupting production.

Example 7:

Separator-Heater Vessel Dimensions W/L: 36"/240"
Maximum Ram Pressure Available: 4000

STAGE 1 CYLINDER
Required Ram Pressure: 3285
Piston Diameter: 12"
Piston Area: 113.14 Square Inches
Ram Diameter: 3.5"
Ram Area: 9.63 Square Inches
Stroke: 108"
Compression Chamber Displacement Volume: 12219.43 Cubic Inches
Stroke/min: 5.5
Ram Displacement Volume: 1039.50 Cubic Inches
Inlet Pressure: 50 PSIG
Maximum Pressure: 340.28

Cylinder Temperature: 346 Degree F
Volume: 26.06 GPM, 247.15 MCFD

STAGE 2 CYLINDER 112.97 PEEK HP REQ.
Required Ram Pressure: 3131
Piston Diameter: 6"
Piston Area: 28.29 Square Inches
Ram Diameter: 3.5"
Ram Area: 9.63 Square Inches
Stroke: 108"
Compression Chamber Displacement Volume: 3054.86 Cubic Inches
Stroke/min: 5.5
Ram Displacement Volume: 1039.50 Cubic Inches
Inlet Pressure: 251 PSIG
Discharge Pressure: 1000 PSIG
Maximum Pressure: 1361.11
Cylinder Temperature: 371 Degree F*
Volume: 26.06 GPM, 246.66 MCFD
Peek HP Required: 107.69
Total HP Required: 76.63
BTU Heat Generation: 2,305,405 Day/Liquid, 1,227,363 Day/Well
Vessel BTU Emission: 6118 BTU/Square Foot
External Cooling: 3868 BTU/Hour
External Tube Area: 1.72 Square Feet
External Tube Length: 78.85'
OD External Tube Size: 1"
Vessel Maximum Duty: 2250 BTU/Square Foot
Pump Volume @ 3600: 52 GPM, 3608 RPM: Average Engine Speed
* Based on 140 Degree Vessel Temperature

Example 8:
Separator-Heater Vessel Dimensions W/L: 24"/180"
Maximum Ram Pressure Available: 4000

STAGE 1 CYLINDER
Required Ram Pressure: 2544
Piston Diameter: 8"

Piston Area: 50.29 Square Inches

Ram Diameter: 2.4375"

Ram Area: 4.67 Square Inches

Stroke: 108"

Compression Chamber Displacement Volume: 5430.86 Cubic Inches

Stroke/min: 6

Ram Displacement Volume: 504.17 Cubic Inches

Inlet Pressure: 40 PSIG

Maximum Pressure: 371.34

Cylinder Temperature: 346 Degree F

Volume: 13.79 GPM, 101.30 MCFD

STAGE 2 CYLINDER 77.46 PEEK HP REQ.

Required Ram Pressure: 2869

Piston Diameter: 4"

Piston Area: 12.57 Square Inches

Ram Diameter: 2.4375"

Ram Area: 4.67 Square Inches

Stroke: 108"

Compression Chamber Displacement Volume: 1357.71 Cubic Inches

Stroke/min: 6

Ram Displacement Volume: 504.17 Cubic Inches

Inlet Pressure: 210 PSIG

Discharge Pressure: 1000 PSIG

Maximum Pressure: 1485.35

Cylinder Temperature: 406 Degree F

Volume: 13.79 GPM, 101.30 MCFD

Example 9:

Example 8 with a third, high compression cylinder:

STAGE 3 CYLINDER 87.36 PEEK HP REQ.

Required Ram Pressure: 3740

Piston Diameter: 2"

Piston Area: 3.14 Square Inches

Ram Diameter: 3"

Ram Area: 7.07 Square Inches

Stroke: 96"

Compression Chamber Displacement Volume: 301.71 Cubic Inches

Stroke/min: 6

Ram Displacement Volume: 678.86 Cubic Inches

Inlet Pressure: 1000 PSIG

Discharge Pressure: 8000 PSIG

Maximum Pressure: 1485.35

Cylinder Temperature: 575 Degree F

Volume: 13.79 GPM, 101.30 MCFD

Fluid Volume Input: 9,000 Maximum Pressure

Water: 18.56 GPM

Total HP Required: 65.21

BTU Heat Generation: 328,336 Day/Liquid, 198,355 Day/Well

Vessel BTU Emission: 1743 BTU/Square Foot

Pump Volume: 46.13 GPM, 3194 RPM: Average Engine Speed

Example 10:

A TRS designed for 40 PSIG separator and 800 PSIG well continuous operating conditions. These pressures result in a 211 degree increase in temperature per cylinder. For natural gas weighing 58 pounds per thousand cubic feet, the compressor pumps 6,506 pounds of gas per day per cylinder. This amounts to 549,106 BTU per day transferred to the liquids in the separator from cooling the cylinders and gas. If additional heat is required, the exhaust from the engine powering the hydraulic pump and jacket water can be diverted to the unit.

Example 11:

A pump attached to the separator in the above examples evacuates the gas and pumps them to the low pressure cylinder. The reduced pressure over the well hole accelerates recovery.

The foregoing disclosure and description of the invention are illustrative and explanatory thereof, and various changes in the use, size, shape and materials, as well as in the details of the illustrated construction may be made without departing from the spirit of the invention.